Arnold Schwarzenegger
Governor

WIND POWER GENERATION TRENDS AT MULTIPLE CALIFORNIA SITES

PIER INTERIM PROJECT REPORT

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Wind Power Generation Trends at Multiple California Sites

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1 INTRODUCTION

1.1 Overview

The importance of wind energy has long been recognized by the California Energy Commission (ENERGY COMMISSION), which supports research and development in renewable energy through its Public Interest Energy Research (PIER) Program. Wind energy provides significant benefits in terms of improved air quality, increased energy supply diversity, in-state energy revenues, and local employment. Still, wind energy development in California faces impediments to its continued growth.

In an effort to foster additional development of wind energy in the state, the ENERGY COMMISSION created the California Wind Energy Collaborative (CWEC), which is managed by the University of California at Davis. The mission of the California Wind Energy Collaborative is to support the development of safe, reliable, environmentally sound, and affordable wind electric generation capacity within the state of California. CWEC works in close cooperation with industry, state and federal agencies, and other institutions to maximize the benefits of wind energy resources for California citizens.

The objective of this project was to document the characteristics of wind power generation at multiple California sites. Representative wind power generation data were obtained and normalized to reflect the average output for three major wind resource regions. The output from each region was compared against the statewide system electrical demand and trends were observed.

1.2 Annual Power Demand

The State of California consumes vast quantities of electric power, with minimum requirements of about 20,000 MW at night and maximum demand near 45,000 MW on hot summer afternoons. The hourly power demand for the California Independent System Operator (CaISO) is published on the Open Access Same-Time Information System (OASIS) website (http://oasis.caiso.com), which provides access to the CaISO's public database. OASIS provides current and archived market data for energy and transmission used by most of California's consumers and businesses.

The CaISO hourly power demand for 2001 through 2003 is shown graphically in Figure 1.1. The minimum power demand during this three year period was 17,515 MW and the maximum was 42,581 MW. The green area of this chart indicates baseline demand, while the blue shows the daily cycles that follow customer load. This chart also shows the demand factor, when the demand was more than 80% of the peak load level. Demand factor is defined as the hourly demand divided by the maximum load in a given year. The graph shows clearly that summer months between May and October define the peak season. The peak demand is strongest during July and August. Table 1.1 provides a listing of the twenty peak load hours in each year from 2001 through 2003.

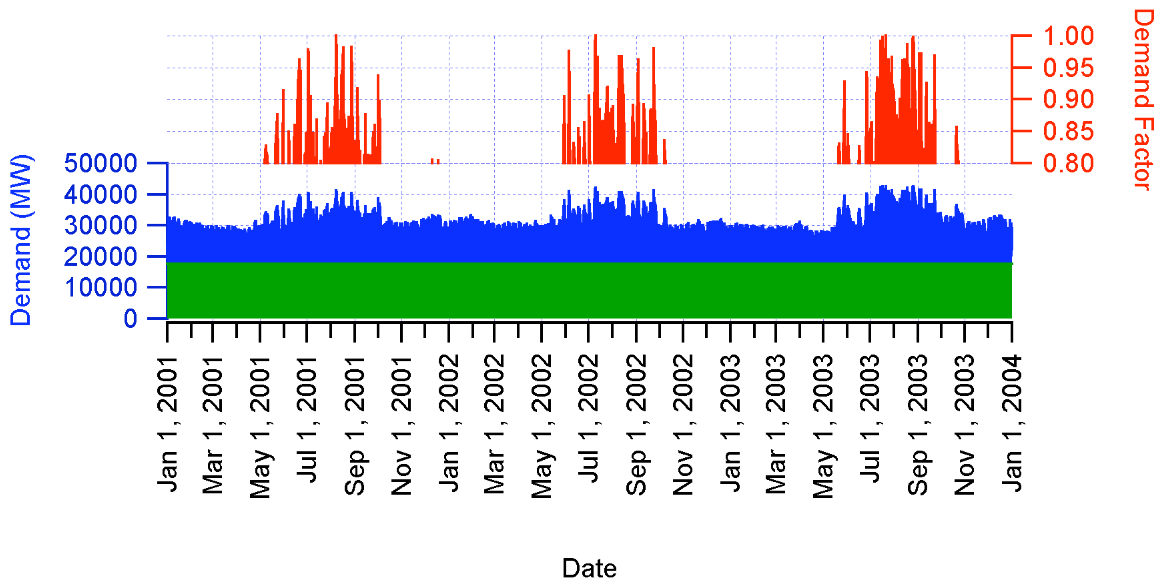

Figure 1.1 California Power Demand for 2001 Through 2003

Table 1.1 California Peak Demand Hours for 2001 Through 2003

Date & Time	Demand (MW)	Date & Time	Demand (MW)	Date & Time	Demand (MW)
8/7/01 15:00	41155	7/10/02 14:00	42008	7/21/03 14:00	42581
8/7/01 16:00	41017	7/10/02 15:00	41813	8/25/03 14:00	42506
8/7/01 14:00	40493	7/9/02 15:00	41636	7/17/03 14:00	42502
8/8/01 15:00	40488	7/9/02 16:00	41480	7/21/03 15:00	42346
8/27/01 15:00	40439	9/23/02 16:00	41165	7/14/03 15:00	42227
8/17/01 15:00	40384	7/9/02 14:00	41162	8/25/03 13:00	42218
7/2/01 15:00	40241	7/10/02 16:00	41092	7/21/03 13:00	42184
8/27/01 16:00	40173	7/10/02 13:00	41007	7/17/03 15:00	42143
8/8/01 14:00	40149	6/5/02 16:00	40986	8/26/03 14:00	42107
7/2/01 16:00	40073	9/23/02 15:00	40984	7/17/03 13:00	42037
7/3/01 15:00	40065	7/9/02 17:00	40935	8/18/03 14:00	42007
8/17/01 14:00	40017	6/5/02 15:00	40858	7/14/03 14:00	41968
8/8/01 16:00	39953	8/9/02 16:00	40638	8/25/03 15:00	41905
8/16/01 15:00	39900	8/9/02 15:00	40625	8/26/03 13:00	41826
8/27/01 14:00	39899	8/12/02 16:00	40625	7/14/03 16:00	41655
8/17/01 16:00	39847	7/12/02 15:00	40614	8/18/03 13:00	41613
7/3/01 14:00	39741	7/10/02 17:00	40520	8/18/03 15:00	41433
8/16/01 16:00	39733	7/12/02 16:00	40488	7/16/03 15:00	41412
7/2/01 14:00	39690	8/12/02 15:00	40429	9/5/03 14:00	41394
7/3/01 13:00	39650	9/3/02 15:00	40418	8/25/03 12:00	41368

The hourly demand factor data were sorted in descending order and are plotted in Figures 1.2 and 1.3. These graphs show power demand as a average hourly fraction of the maximum system load during the year. The graphs illustrate that system demand is typically above 80% of maximum for less than five hundred hours per year. These graphs also show that although similar trends exist from year-to-year, there can be considerable variation depending upon weather conditions, economic growth impacts, and changing customer habits.

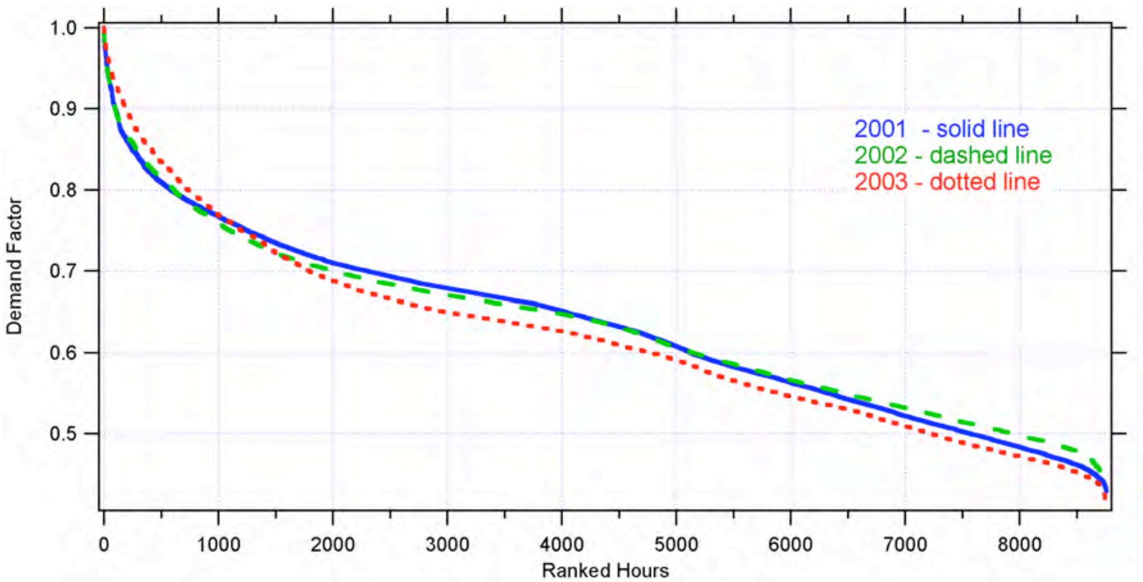

Figure 1.2 Ranked Demand Factor for 2001 Through 2003

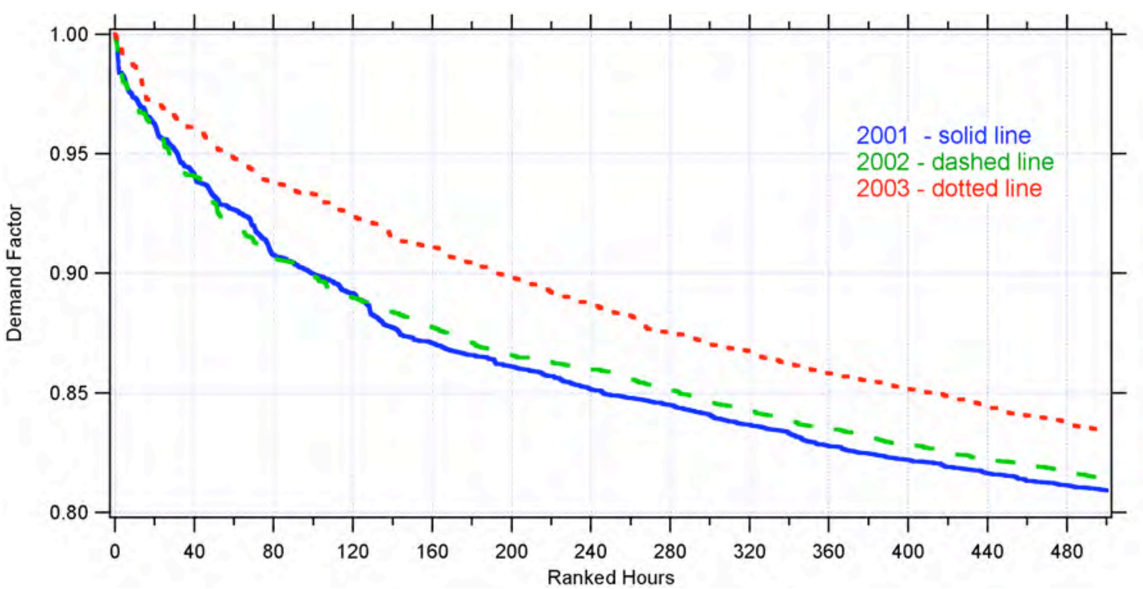

Figure 1.3 Ranked Demand Factor for 500 Peak Hours

1.3 Diurnal Power Demand

Power demand shows a strong diurnal variation of between 8,000 and 18,000 MW over the course of a given day. The diurnal variation becomes more pronounced in the summer months due to air conditioning demands. Average daily power demand was calculated on a monthly basis for 2002 and is shown graphically in Figures 1.6 through 1.9. These data were converted to a non-dimensional form called a demand factor. The demand factor was calculated by dividing the hourly system load value by the peak power during 2002. The graphs show hourly demand as a fraction of the maximum system demand averaged over each month and are arranged by quarter.

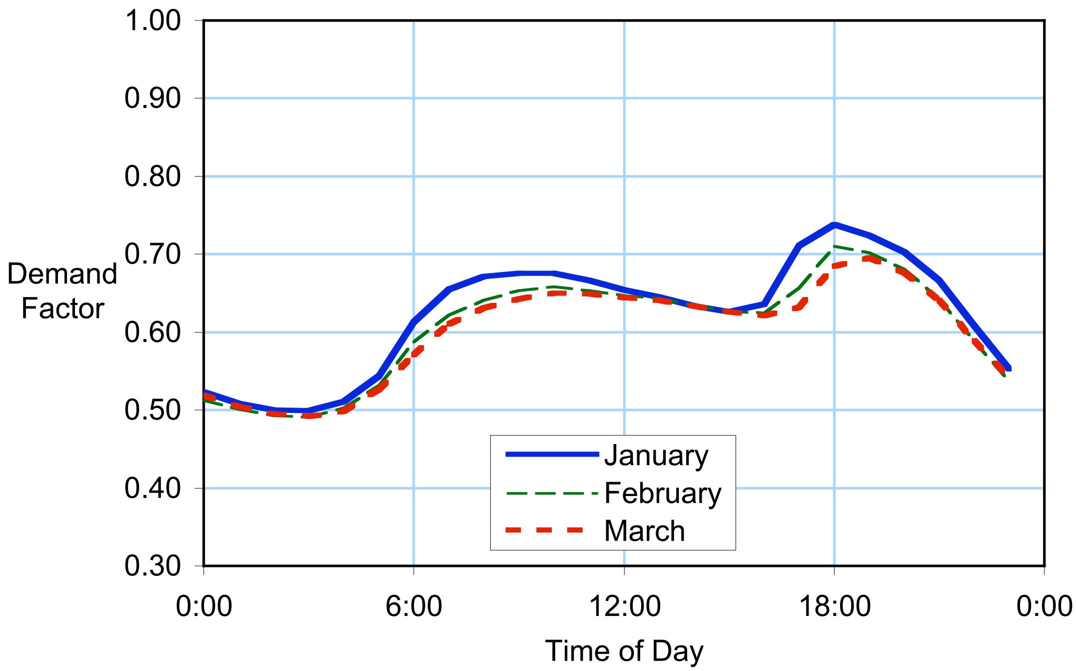

Figure 1.4 Diurnal Power Demand During the First Quarter of 2002

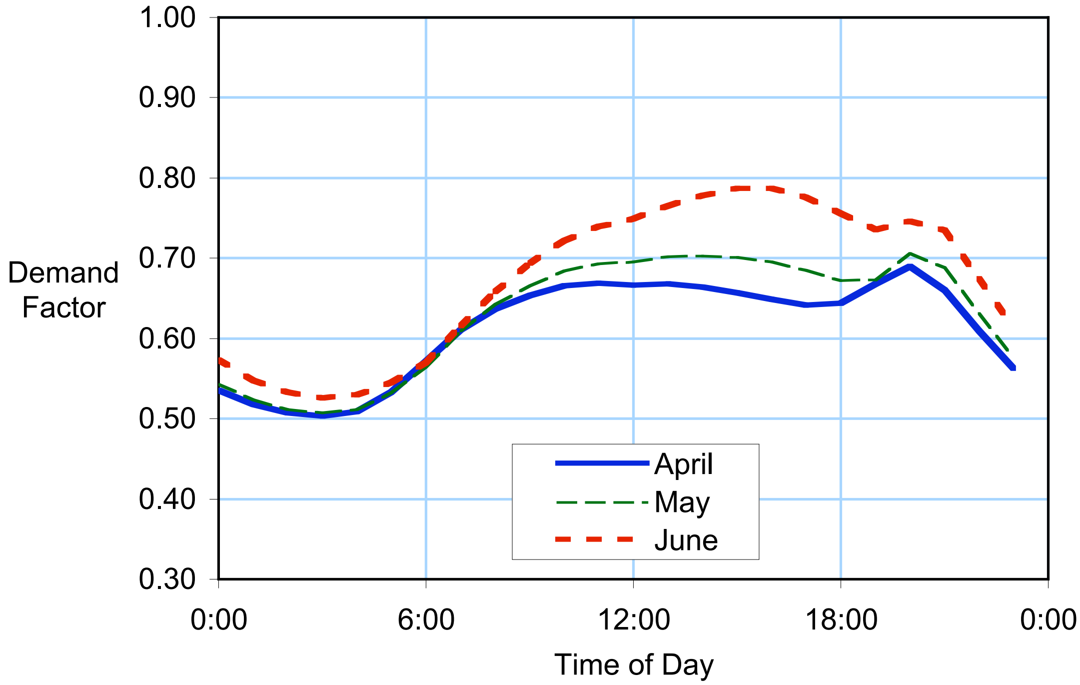

Figure 1.5 Diurnal Power Demand During the Second Quarter of 2002

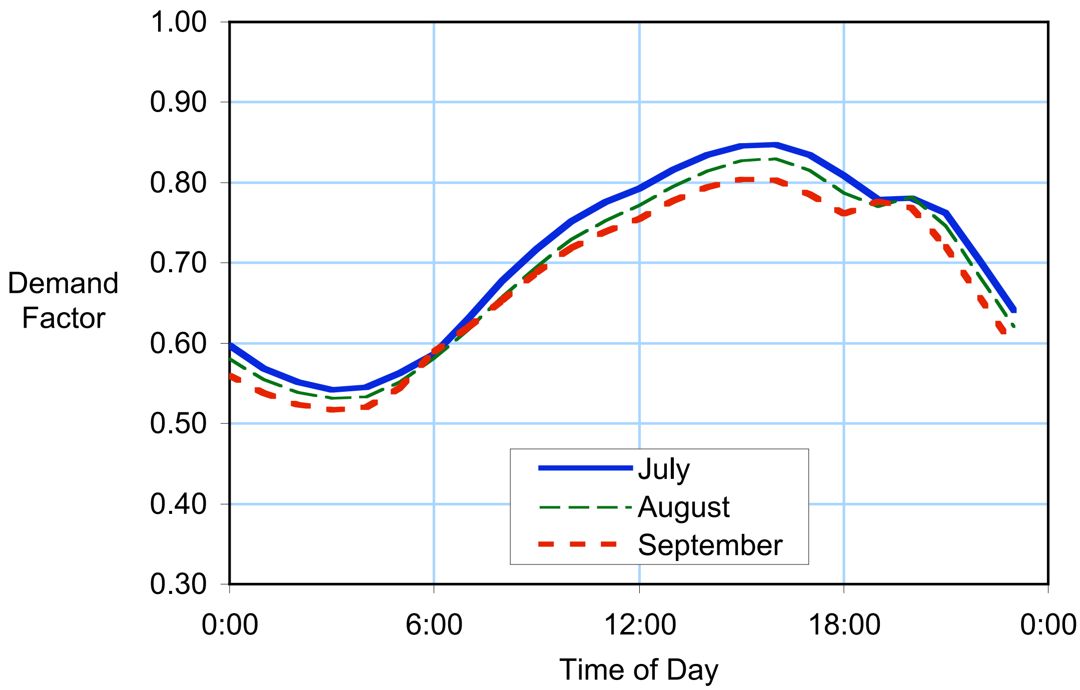

Figure 1.6 Diurnal Power Demand During the Third Quarter of 2002

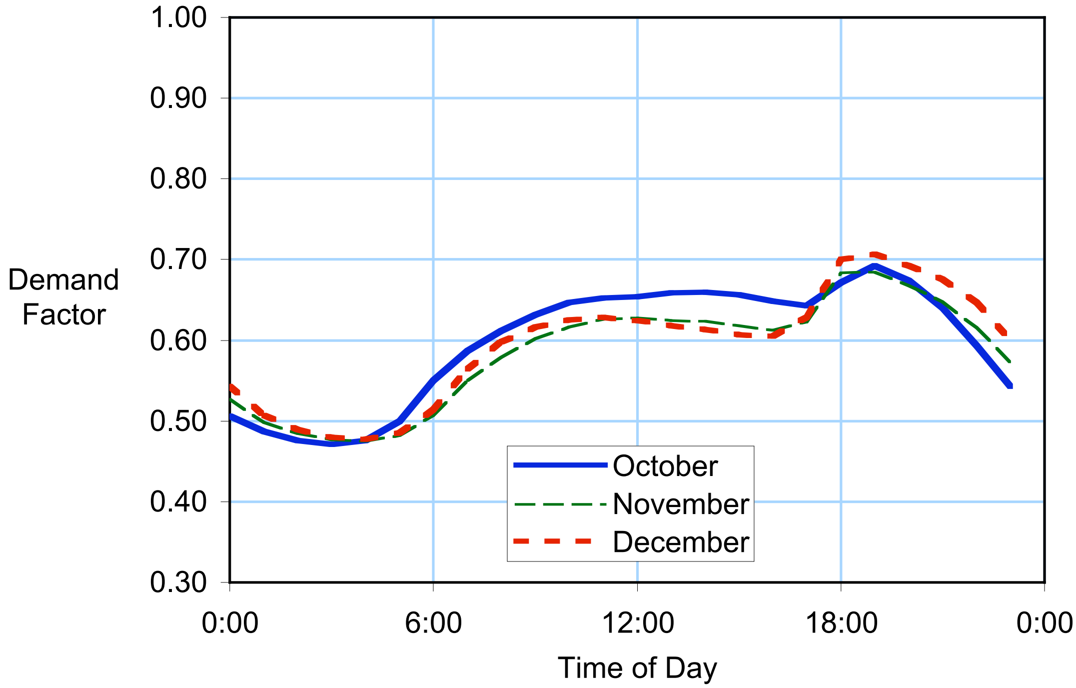

Figure 1.7 Diurnal Power Demand During the Fourth Quarter of 2002

1.4 Wind Resources

California's wind resources are broadly summarized in Table 1.2. This table provides the land area available within the state as a function of both the mean wind speed and the hub height. Assuming a 70 meter hub height, there are about 2,000 square miles of land available for current technology wind turbines, which have been optimized for wind speeds greater than 7.5 m/s. In comparison there are approximately 25,000 square miles if one assumes future wind systems can effectively use mean wind speeds near 6 m/s.

Table 1.2 California Land Area in Square Miles for Various Wind Speeds and Heights
(from New Wind Energy Resource Maps of California, ENERGY COMMISSION-P500-03-55F)

Height (m)			Mean Speed (m/s)				
	<4.5	4.5-5.5	5.5-6.5	6.5-7.5	7.5-8.5	>8.5	
30	105161	38555	11136	2644	621	221	
		<5.5	5.5-6.5	6.5-7.5	7.5-8.5	8.5-9.5	>9.5
50		134716	17695	4583	1016	257	72
70		125374	24488	6593	1471	331	83
100		114033	32208	9524	2058	415	100

During 2003 the ENERGY COMMISSION evaluated renewable resources within the state and prepared estimates for how they might be developed to meet the requirements of the Renewable Portfolio Standard (RPS), which mandates increased use of renewable energy by utilities. The ENERGY COMMISSION published a Renewable Resources Development Report [1], which estimated California wind capacity growth through 2017 and projected the total wind generation and the geographical location of the wind plants. Capacity growth estimates were prepared for both baseline and accelerated implementation scenarios. The baseline scenario assumed the RPS goal of 20% renewable energy would be met in 2017, while the accelerated scenario assumed that goal would be reached in 2010.

Wind capacity data obtained from the Renewable Resources Development Report are summarized in Table 1.3 for the baseline and Table 1.4 for the accelerated RPS implementation scenario. The total amount of new wind power capacity in 2017 was estimated to be 6,445 MW for both scenarios, although the development will occur earlier in the accelerated development case.

The ENERGY COMMISSION data indicate that about 70% of new wind development can be expected to occur in the Tehachapi resource area (Figure 1.8). The San Gorgonio Pass region has the next largest share with 15%, while the Solano County and San Diego County resource areas each add 6%, and the Altamont Pass region provides a final 3%. Table 1.5 summarizes the annual and cumulative growth in wind energy capacity expected under the RPS. The locations of California's primary wind resource regions are mapped in Figures 1.9 and 1.10.

Table 1.3 Wind Power Capacity Growth for the Baseline Scenario

Resource Area	**New RPS Wind Power Capacity (MW)**				
County	Proposed	2005	2008	2017	Total
Altamont					
Alameda	210	50	110	50	210
San Gorgonio					
Riverside	530	200	190	140	530
San Bernardino	90	50	40	310	400
Solano					
Solano	400	215	100	85	400
Tehachapi					
Kern	3,790	285	1,410	2,365	4,060
Los Angeles	100	100		315	415
Other					
San Diego	400		200	200	400
Other	30			30	30
Statewide					
Total	5,550	900	2,050	3,495	6,445

Source: Renewable Resources Development Report

Table 1.4 Wind Power Capacity Growth for the Accelerated Scenario

Resource Area	**New RPS Wind Power Capacity (MW)**					
County	Proposed	2005	2008	2010	2017	Total
Altamont						
Alameda	210	50	135	5	20	210
San Gorgonio						
Riverside	530	250	280			530
San Bernardino	90	50	60		290	400
Solano						
Solano	400	315	85	-		400
Tehachapi						
Kern	3,790	395	1,910	1,425	330	4,060
Los Angeles	100	100	35		280	415
Other						
San Diego	400	200	200			400
Other	30	30				30
Statewide						
Total	5,550	1,390	2,705	1,430	920	6,445

Source: Renewable Resources Development Report

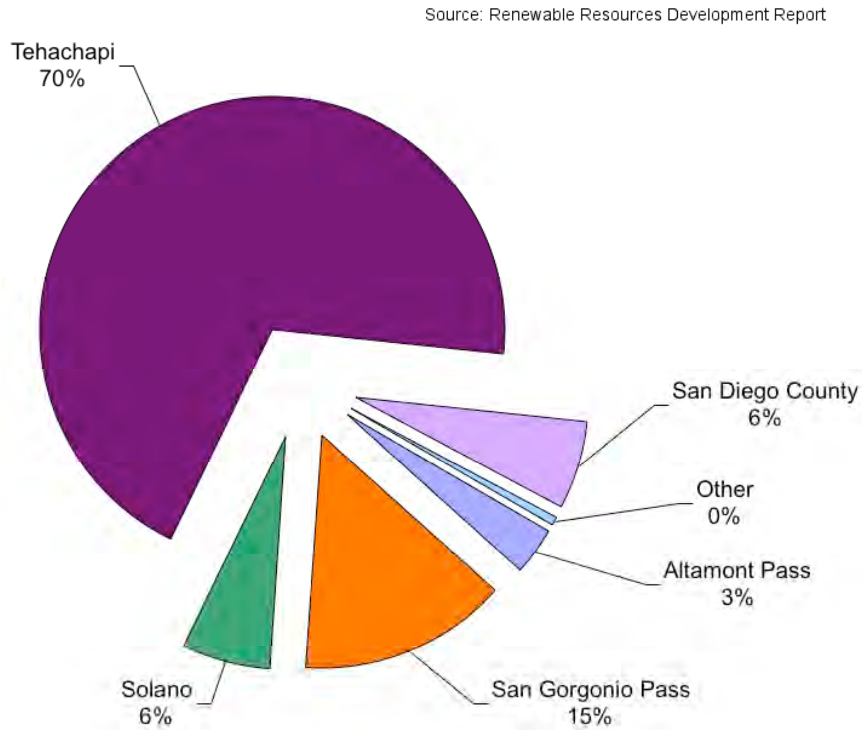

Figure 1.8 Estimated Share of Future Wind Energy Growth by Resource Area

Table 1.5 Estimated Statewide Wind Power Annual and Cumulative Capacity Growth by Year for Both RPS Scenarios

Year	Baseline		Accelerated	
	Annual (MW)	Cumulative (MW)	Annual (MW)	Cumulative (MW)
2005	900	900	1390	1390
2006	683	1583	902	2292
2007	683	2267	902	3193
2008	683	2950	902	4095
2009	500	3450	715	4810
2010	500	3950	715	5525
2011	356	4306	131	5656
2012	356	4663	131	5788
2013	356	5019	131	5919
2014	356	5376	131	6051
2015	356	5732	131	6182
2016	356	6089	131	6314
2017	356	6445	131	6445

Source: Renewable Resources Development Report

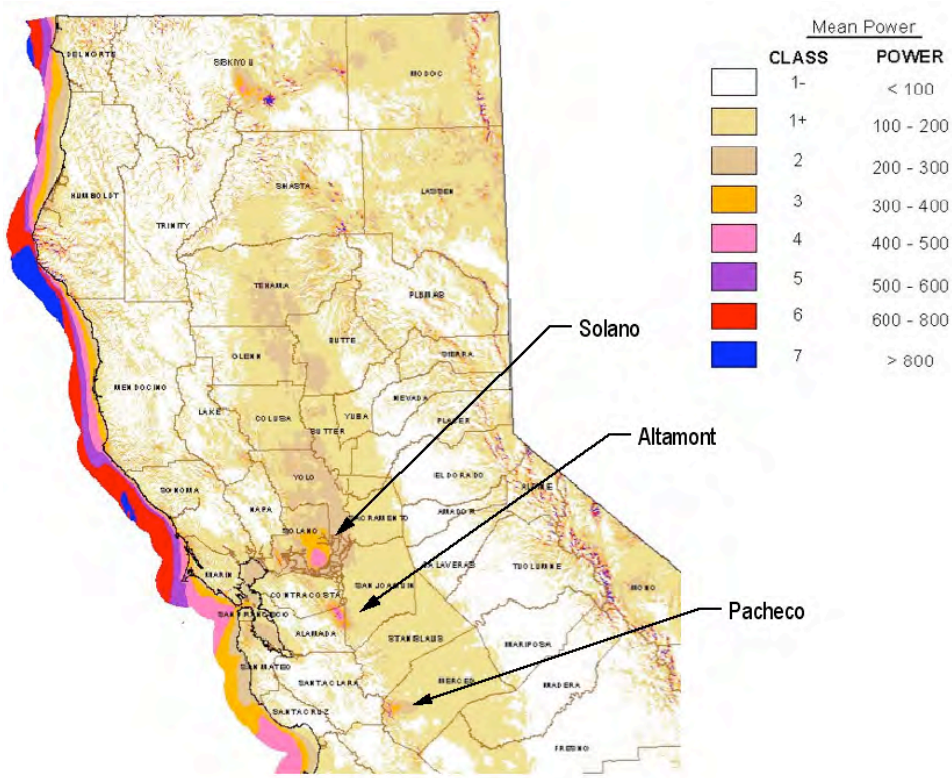

Figure 1.9 Wind Resource Map of Northern California

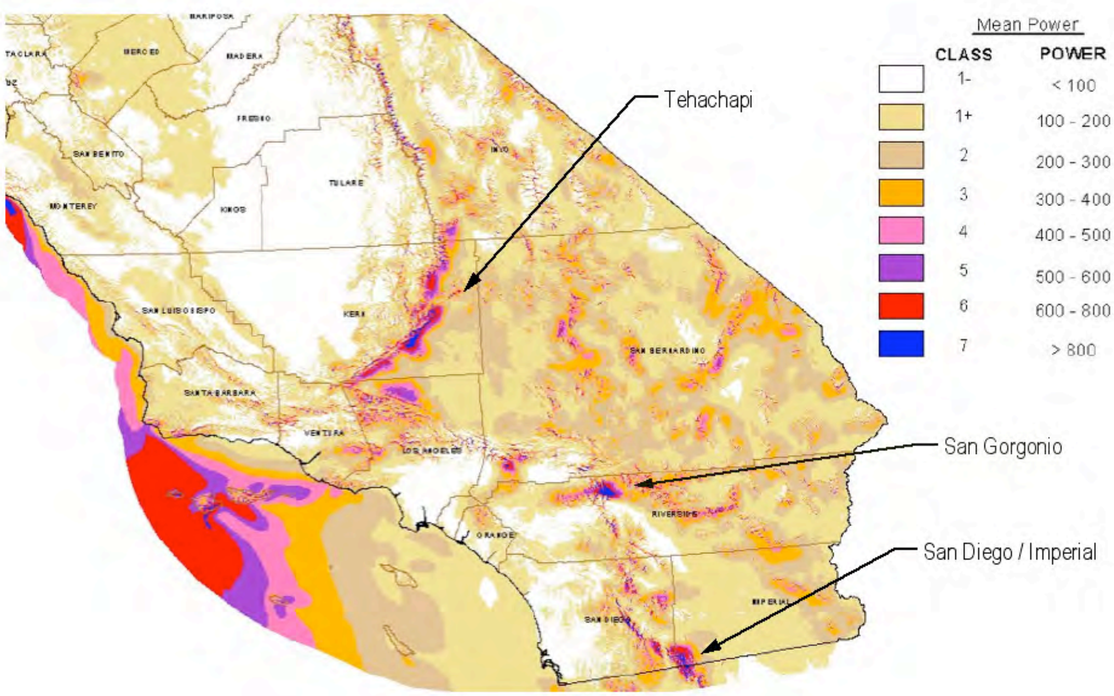

Figure 1.10 Wind Resource Map of Southern California

2 WIND GENERATION TRENDS

2.1 Multi-year Trends

The ENERGY COMMISSION has collected a variety of performance data from wind turbine operators since the mid-1980's, through a program known as the Wind Performance Reporting System (WPRS). Recently these data were organized by the California Wind Energy Collaborative and published on a website (http://cwec.ucdavis.edu). The WPRS database can be queried to sort the data in a variety of ways. In this report the wind capacity factor data were tabulated by quarter for each resource region over a six year period from 1996 through 2002 (Tables 2.1 to 2.4).

It is important to note that differences in capacity factor between regions can be a consequence of both the wind resource and the mix of wind turbine equipment operating in each region. The age and type of equipment vary considerably between resource areas and the Altamont Pass region has not benefited by the introduction of new wind turbine technology to the same degree as the other major resource areas in California.

Table 2.1 Altamont Wind Capacity Factor by Year

Year	Altamont Capacity Factor (%)				
	Q1	Q2	Q3	Q4	Mean
1996	7	24	28	7	17
1997	7	28	28	5	17
1998	5	21	24	4	14
1999	7	32	33	6	19
2000	7	26	27	7	17
2001	8	27	46	8	22
2002	4	32	30	7	18
Mean	6.4	27.1	30.9	6.3	17.7

Table 2.2 San Gorgonio Wind Capacity Factor by Year

Year	San Gorgonio Capacity Factor (%)				
	Q1	Q2	Q3	Q4	Mean
1996	27	53	29	15	31
1997	19	44	27	14	26
1998	19	72	28	16	34
1999	24	41	29	15	27
2000	23	41	33	16	28
2001	19	41	28	15	26
2002	17	50	33	20	30
Mean	21.1	48.9	29.6	15.9	28.9

Table 2.3 Tehachapi Wind Capacity Factor by Year

Year	Tehachapi Capacity Factor (%)				
	Q1	Q2	Q3	Q4	Mean
1996	20	40	23	20	26
1997	20	40	16	16	23
1998	24	33	19	23	25
1999	26	37	22	15	25
2000	24	40	29	20	28
2001	20	39	27	19	26
2002	21	44	32	19	29
Mean	22.1	39.0	24.0	18.9	26.0

Table 2.4 Solano Wind Capacity Factor by Year

Year	Solano Capacity Factor (%)				
	Q1	Q2	Q3	Q4	Mean
1996	7	18	30	8	16
1997	6	22	24	5	14
1998	3	12	20	4	10
1999	3	27	31	5	17
2000	5	27	28	5	16
2001	7	18	3	7	9
2002	20	26	29	5	20
Mean	7.3	21.4	23.6	5.6	14.6

The WPRS performance data were also organized by quarter in Tables 2.5 to 2.8 to simplify comparison between the wind resource regions.

Table 2.5 First Quarter Wind Capacity Factor by Year

Year	First Quarter Capacity Factor (%)				
	Altamont	San Gorgonio	Solano	Tehachapi	Statewide
1996	7	27	7	20	15.3
1997	7	19	6	20	13.0
1998	5	19	3	24	12.8
1999	7	24	3	26	15.0
2000	7	23	5	24	14.8
2001	8	19	7	20	13.5
2002	4	17	20	21	15.5
Mean	6.4	21.1	7.3	22.1	14.3

Table 2.6 Second Quarter Wind Capacity Factor by Year

Year	Second Quarter Capacity Factor (%)				
	Altamont	San Gorgonio	Solano	Tehachapi	Statewide
1996	24	53	18	40	33.8
1997	28	44	22	40	33.5
1998	21	72	12	33	34.5
1999	32	41	27	37	34.3
2000	26	41	27	40	33.5
2001	27	41	18	39	31.3
2002	32	50	26	44	38.0
Mean	27.1	48.9	21.4	39.0	34.1

Table 2.7 presents data from the third quarter (July, August, September), which show that the Altamont resource area has the highest capacity factor, followed by San Gorgonio, Tehachapi, and Solano. Ranking using the Q3 data places Altamont first and San Gorgonio second, Tehachapi third, and Solano fourth. It is worth noting that the Solano data for 2001 are extremely low and are not believed to be representative of this resource area. When those data are excluded from the analysis the average Q3 capacity factor for Solano is 27% and it is ranked in third place.

Table 2.7 Third Quarter Wind Capacity Factor by Year

Year	Third Quarter Capacity Factor (%)				
	Altamont	San Gorgonio	Solano	Tehachapi	Statewide
1996	28	29	30	23	27.5
1997	28	27	24	16	23.8
1998	24	28	20	19	22.8
1999	33	29	31	22	28.8
2000	27	33	28	29	29.3
2001	46	28	3	27	26.0
2002	30	33	29	32	31.0
Mean	30.9	29.6	23.6	24.0	27.0

Table 2.8 Fourth Quarter Wind Capacity Factor by Year

Year	Fourth Quarter Capacity Factor (%)				
	Altamont	San Gorgonio	Solano	Tehachapi	Statewide
1996	7	27	8	20	15.5
1997	5	19	5	16	11.3
1998	4	19	4	23	12.5
1999	6	24	5	15	12.5
2000	7	23	5	20	13.8
2001	8	19	7	19	13.3
2002	7	17	5	19	12.0
Mean	6.3	21.1	5.6	18.9	13.0

Table 2.9 Mean Annual Wind Capacity Factor by Year

Year	Annual Capacity Factor (%)				
	Altamont	San Gorgonio	Solano	Tehachapi	Statewide
1996	17	31	16	26	22.5
1997	17	26	14	23	20.0
1998	14	34	10	25	20.8
1999	19	27	17	25	22.0
2000	17	28	16	28	22.3
2001	22	26	9	26	20.8
2002	18	30	20	29	24.3
Mean	17.7	28.9	14.6	26.0	21.8

2.2 Monthly Generation Trends

In recent years the WPRS data have been submitted on a monthly basis. Tables 2.10 and 2.11 provide a summary of the monthly capacity factor for the three leading resource areas during 2002 and 2003. These data show that average monthly wind capacity factor exceeded 30% at all three resource areas from May through August 2002. June was the peak month for capacity factor in all three regions and the maximum value was 54% in the San Gorgonio area. The monthly capacity factor data are presented graphically in Figures 2.1 and 2.2.

Table 2.10 2002 Monthly Capacity Factor by Resource Area

Month	Monthly Capacity Factor (%)		
2002	Tehachapi	San Gorgonio	Altamont
January	18.6	11.6	1.5
February	20.5	14.2	8.6
March	25.2	26.7	3.1
April	40.8	48.4	24.2
May	46.1	47.7	32.6
June	48.8	54.1	41.0
July	30.8	36.3	36.5
August	38.7	35.1	32.6
September	27.4	28.1	19.7
October	23.9	32.3	15.5
November	17.9	13.9	4.4
December	17.4	14.1	3.7
Annual	29.7	30.2	18.6
Q1	21.4	17.5	4.4
Q2	45.2	50.1	32.6
Q3	32.3	33.1	29.6
Q4	19.7	20.1	7.9

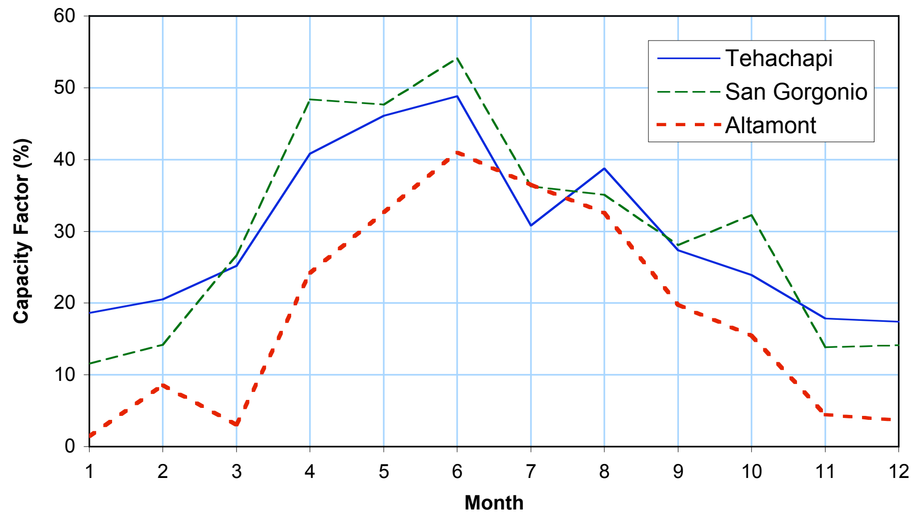

Figure 2.1 2002 Monthly Capacity Factor by Resource Area

Wind capacity factor in the southern California resource areas was substantially lower in 2003 as compared to 2002. June was again the peak month, with a maximum capacity factor of 46.1% in Tehachapi and 43.9% in San Gorgonio. Tehachapi capacity factor during the month of August was 38.7% in 2003 and just 22.3% in 2002. These data show that substantial differences in wind generation can occur from year-to-year. Understanding inter-annual variation will be important for long term capacity planning. Further efforts to statistically quantify multi-year generation trends using the WPRS database can provide improved guidance on the potential range of variation.

Table 2.11 2003 Monthly Capacity Factor by Resource Area

Month 2003	Monthly Capacity Factor (%)		
	Tehachapi	San Gorgonio	Altamont
January	19.7	6.5	2.5
February	25.9	17.8	4.6
March	34.5	24.3	12.5
April	35.2	51.5	15.3
May	39.6	40.5	44.6
June	46.1	43.9	43.3
July	36.5	29.9	28.2
August	22.3	22.0	29.7
September	20.3	18.5	26.3
October	21.1	15.7	17.0
November	19.5	14.2	2.1
December	21.2	11.9	2.4
Annual	28.5	24.7	19.0
Q1	26.7	16.2	6.5
Q2	40.3	45.3	34.4
Q3	26.4	23.5	28.1
Q4	20.6	13.9	7.2

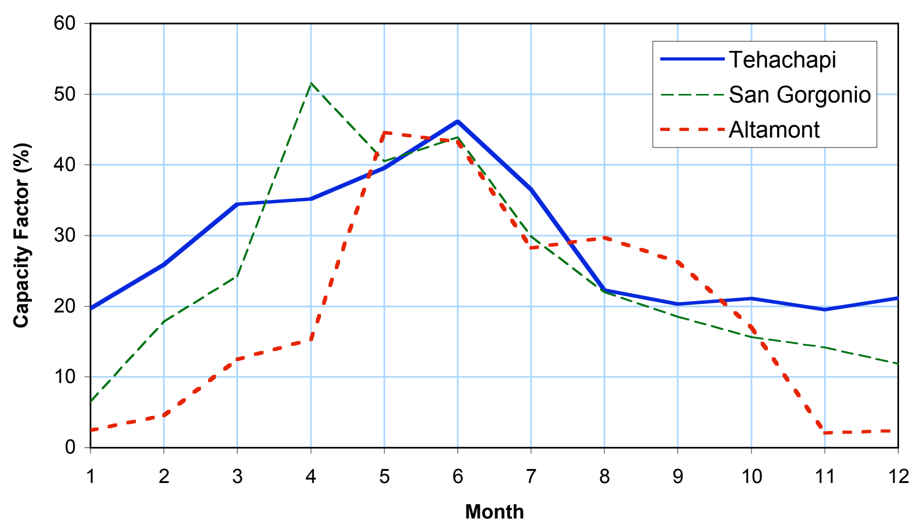

Figure 2.2 2003 Monthly Capacity Factor by Resource Area

2.3 Diurnal Generation Trends

Wind generation is dependent upon weather conditions, which tend to follow seasonal and diurnal trends. Hourly wind capacity factor data for three resource areas were used to evaluate the daily trends. The hourly capacity factor for 2002 was obtained for representative wind plants in each resource region and was scaled so that the annual capacity factor was equal to the value published in the WPRS. These data were then sorted into a table with one row for each day and

24 columns for each hour of the day. These data show that both southern California sites show similar diurnal behavior, but Altamont has a different generation pattern during the winter months (Figure 2.3).

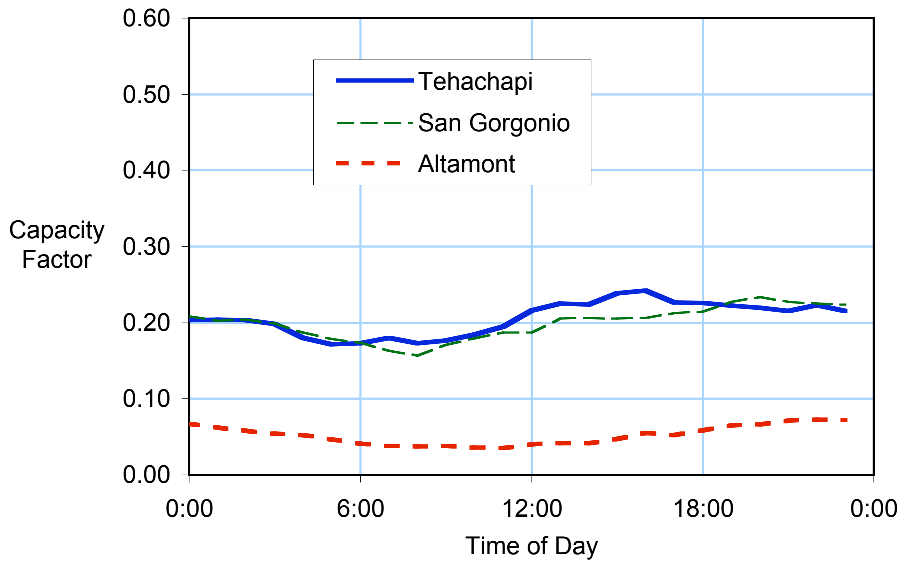

Figure 2.3 Diurnal Wind Generation Trends During the First Quarter of 2002

A characteristic diurnal generation pattern is evident in the spring and summer months. Relatively higher ambient temperatures inland generate strong marine flows on a daily basis. This marine flows strengthen as the day progresses and peak wind generation occurs between 19:00 and 22:00 hours. For consistency time of day is defined in Pacific Standard Time (PST). From April through October California observes Pacific Daylight Time (PDT), so local time in Figures 2.4 and 2.5 will be shifted by one hour.

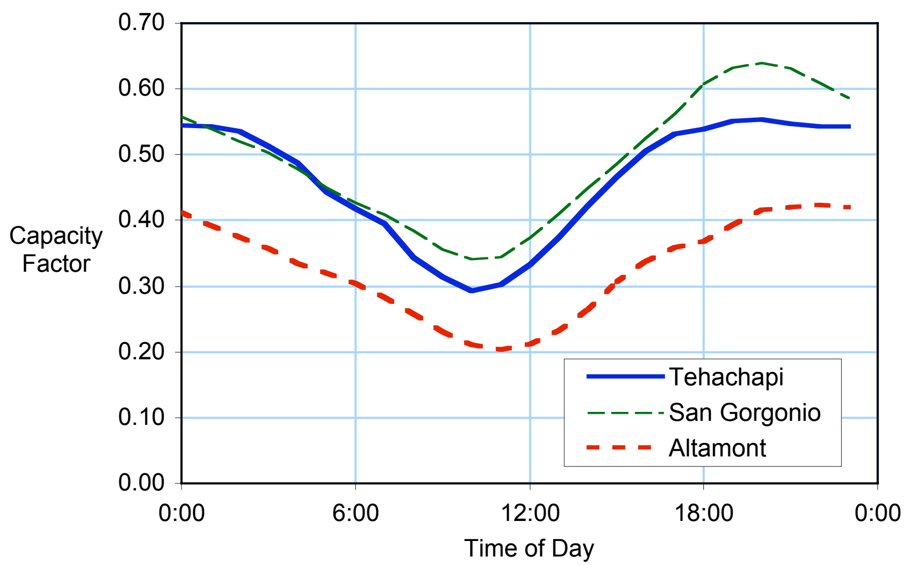

Figure 2.4 Diurnal Wind Generation Trends During the Second Quarter of 2002

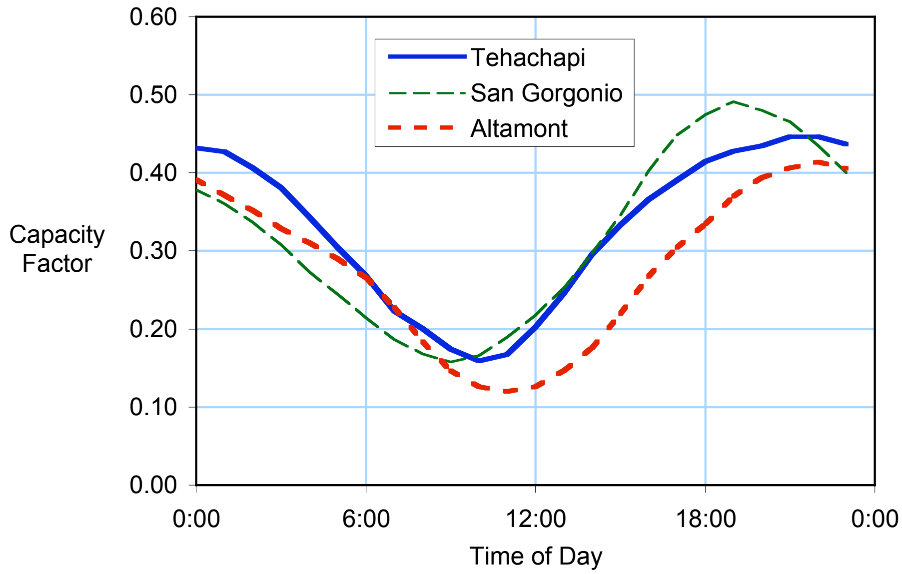

Figure 2.5 Diurnal Wind Generation Trends During the Third Quarter of 2002

The diurnal pattern in the autumn is much the same as that found in the winter months, as shown in Figure 2.6. The two southern California sites have similar behavior, while the northern California site is substantially different.

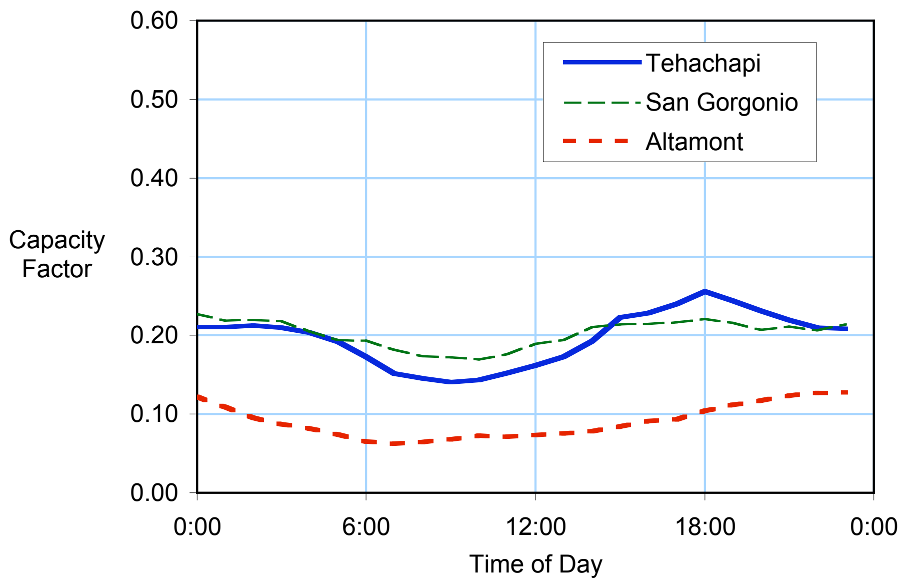

Figure 2.6 Diurnal Wind Generation Trends During the Fourth Quarter of 2002

2.4 Normalized Time Series

Wind generation data plotted as normalized capacity factor are shown in Figure 2.7 for a peak demand period and in Figures 2.8 and 2.9 for two other summer periods. These normalized data provide the trends for subsequent analyses of each resource area.

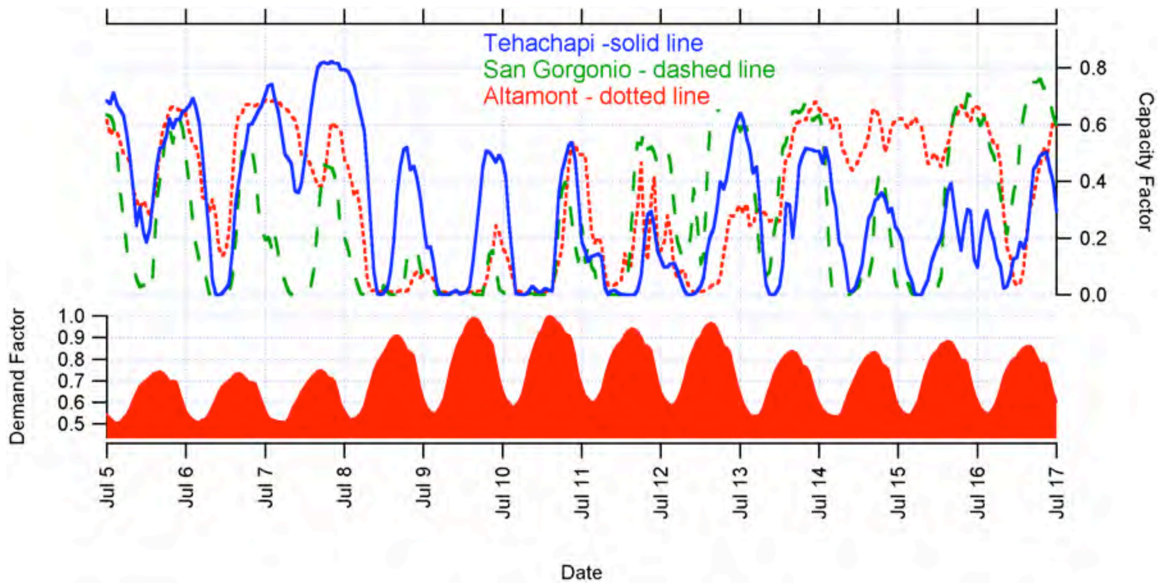

Figure 2.7 Capacity Factor Comparison During a Peak Demand Period

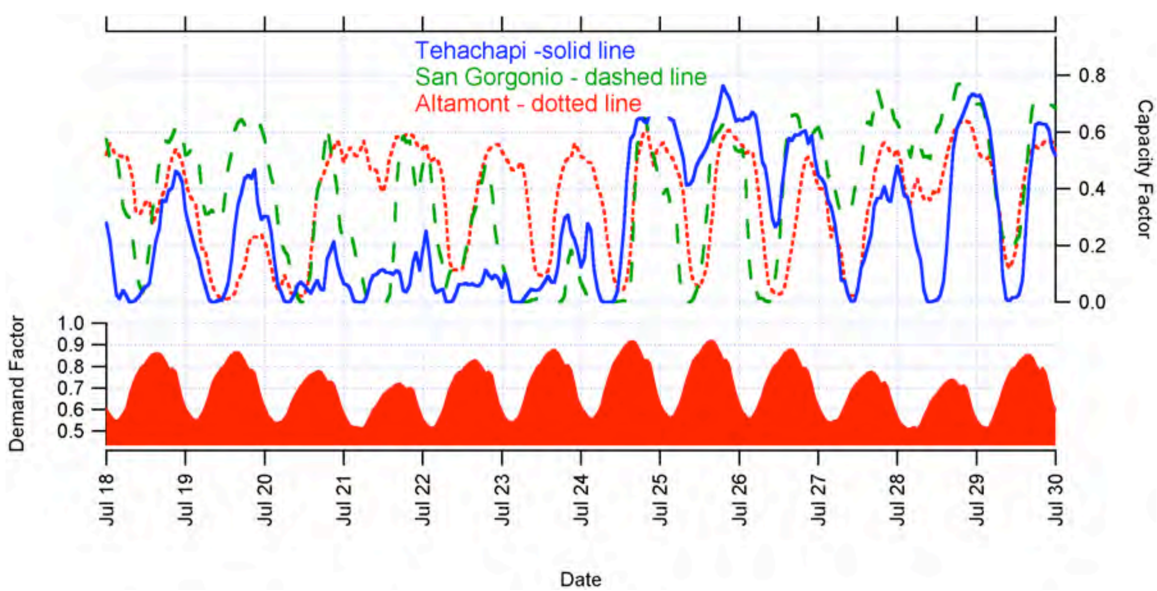

Figure 2.8 Wind Capacity Factor Comparison During July 2002

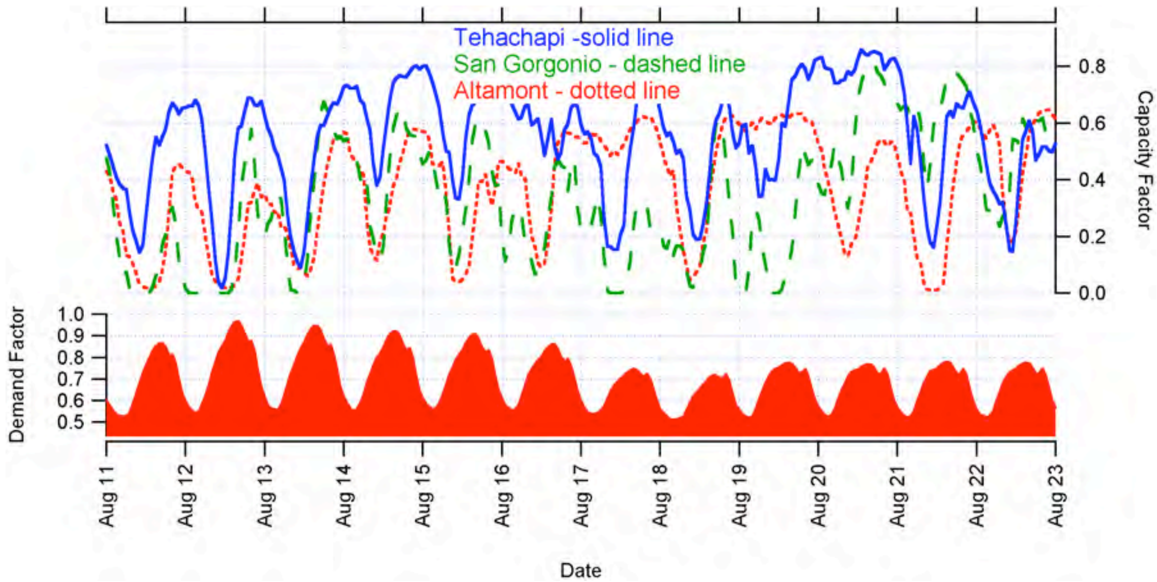

Figure 2.9 Wind Capacity Factor Comparison During August 2002

3 TIME DEPENDENT VALUATION

The value of electric generation varies depending upon the time of day or the season of the year. Time dependent valuation provides a means for evaluating and comparing different wind resource areas and wind generation technologies by incorporating the increased value of electricity provided during peak load hours. For purposes of this effort we performed time dependent valuation using both a demand based and a tier based methodology.

3.1 Demand Based Valuation

The demand based technique used an equation to calculate a time dependent electricity value using total system load. The value factor was defined as:

$$\text{Value Factor} = \left| \frac{1}{1 + R - D} \right|$$

where:
D = demand factor
R = reserve factor (1%, 3%, 10%)
Value factor consists of 8760 hourly values
which have an annual average normalized to unity

The demand dependent value analysis assumed three different reserve factors of 1%, 3%, and 10%. The demand factor was calculated using CaISO system demand data and normalized using the peak load experienced during the 2002 analysis period. The demand based value factor was calculated for each hour and for each of the three reserve factors. The results were normalized so that the average value factor for the year was equal to unity (average = 1). Using this model the value of electricity is highest on hot summer days as shown in Figures 3.1 and 3.2. These graphs show that the value factor can be as much as 30 times the average value for the 1% reserve case.

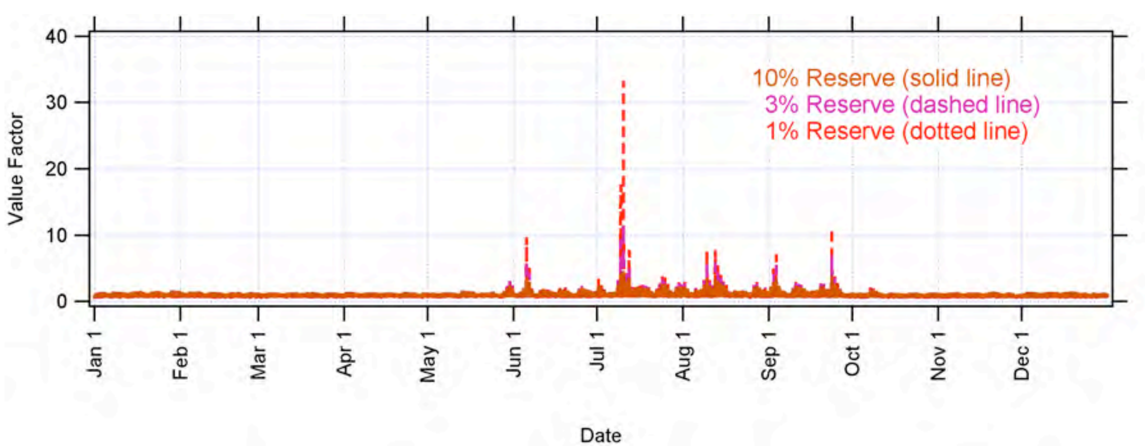

Figure 3.1 Demand Based Value Factor as a Function of Time of Year

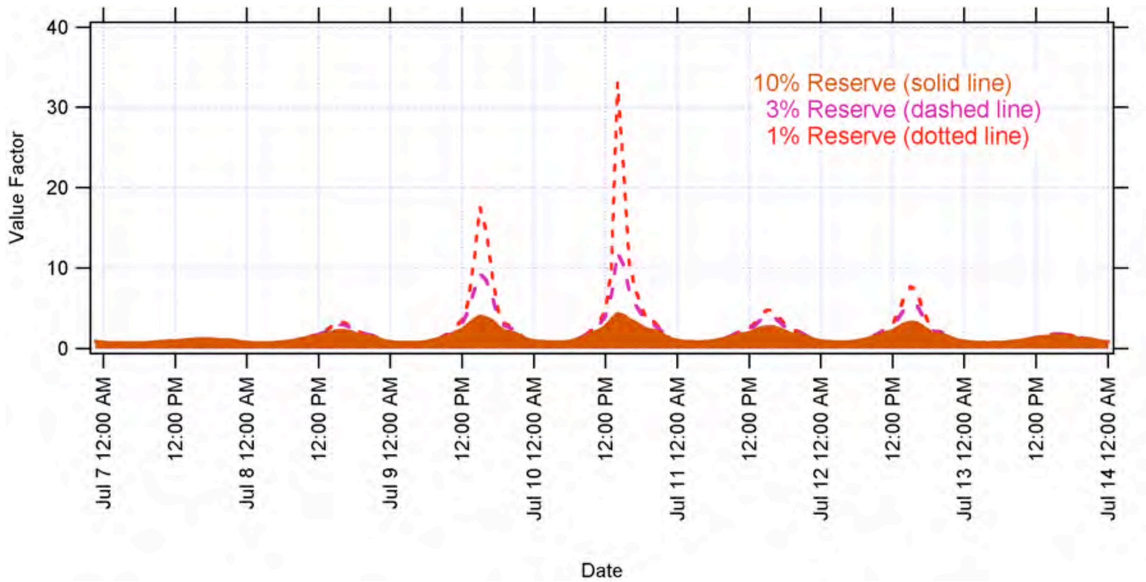

Figure 3.2 Demand Based Value Factor During a Peak Demand Period

A revenue factor was calculated by multiplying the demand based value factor by the generator capacity factor. An example of hourly wind revenue, assuming 10% reserve, is presented in Figures 3.3 during a peak demand period in early July 2002. Figures 3.4 and 3.5 present revenue factor data for late July and mid-August 2002. Comparison of the annual average revenue between constant and demand based valuation is provided in Table 3.1. Relatively small differences between the constant valuation and the demand based valuation revenue factors were observed.

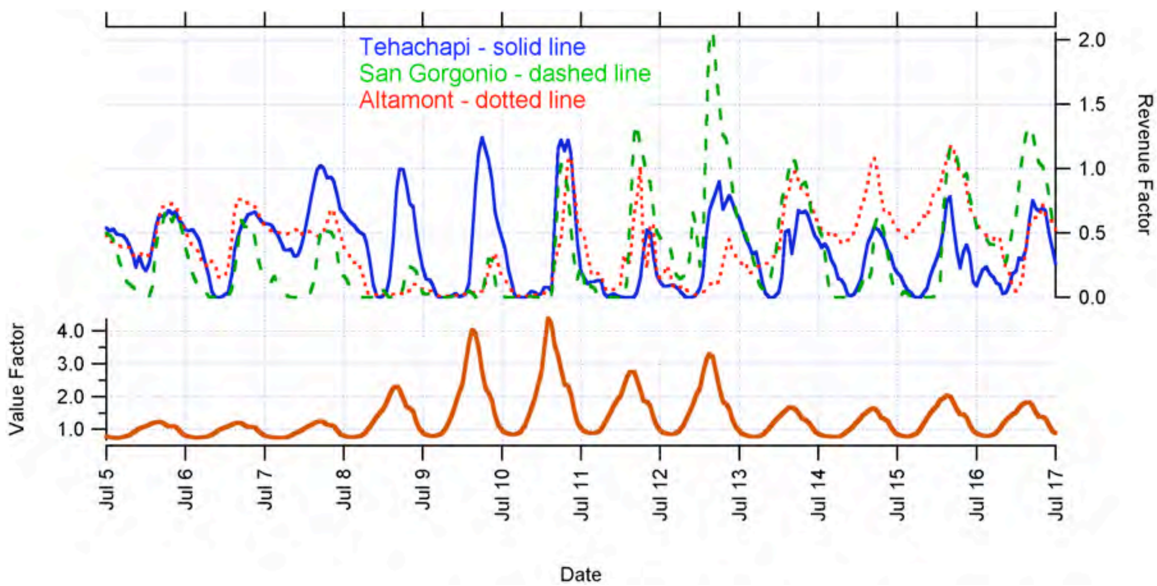

Figure 3.3 Demand Based Revenue Factor During a Peak Demand Period

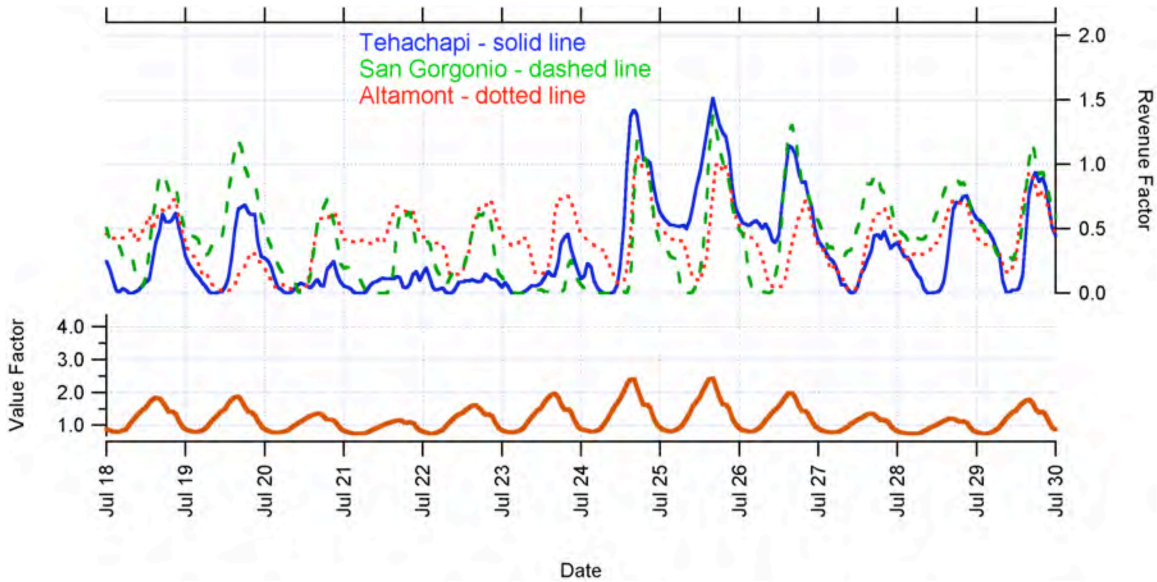

Figure 3.4 Demand Based Revenue Factor During July 2002

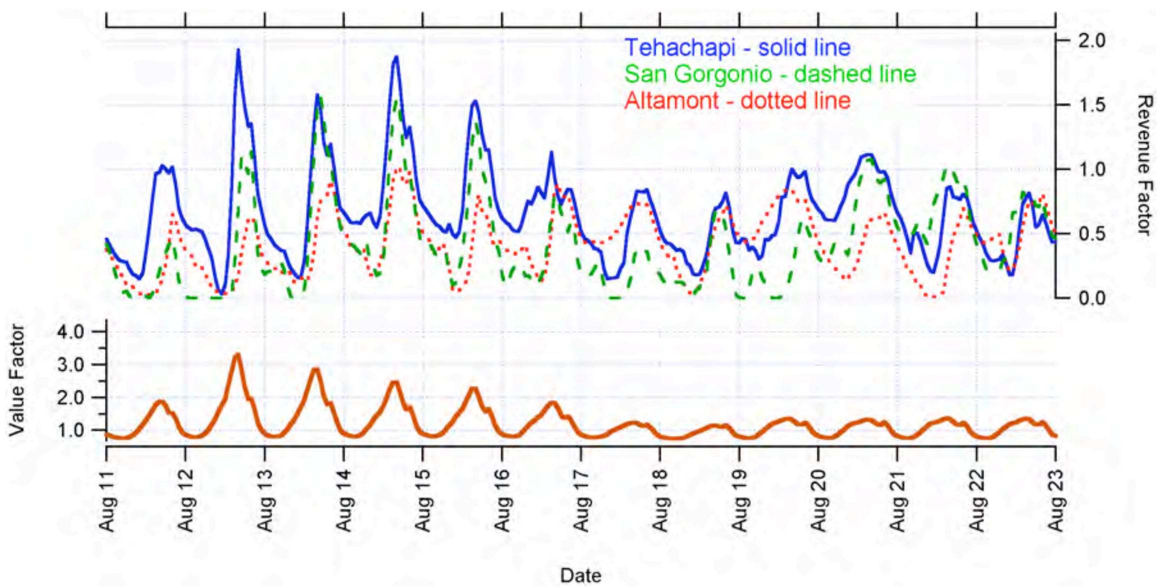

Figure 3.5 Demand Based Revenue Factor During August 2002

Table 3.1 Demand Based Revenue Factor Comparison Summary

Revenue Factor	Constant Value	Demand Based Value		
		1% Reserve	3% Reserve	10% Reserve
Tehachapi	29.7%	29.5%	29.6%	29.7%
San Gorgonio	30.2%	30.0%	30.3%	30.4%
Altamont	18.6%	18.6%	18.8%	18.9%

3.2 Tier Based Valuation

Tier based valuation applies a common approach used in electric power systems. Under this method the value of electricity depends upon a fixed schedule. There are several tiers and payment rates change with the time of day and season of the year. The tier based scheme used four payment levels (on-peak, mid-peak, off-peak, and super off-peak) to define the value of electricity during any given day. The tier values were adjusted monthly and were based on actual time dependent payment rates for a southern California wind plant during 2002. The tier based time dependent value factor was normalized so that the average value for the year was equal to unity. Figure 3.6 presents the tier based time dependent value factor for the whole year, while Figure 3.7 graphs data for a peak demand period in July.

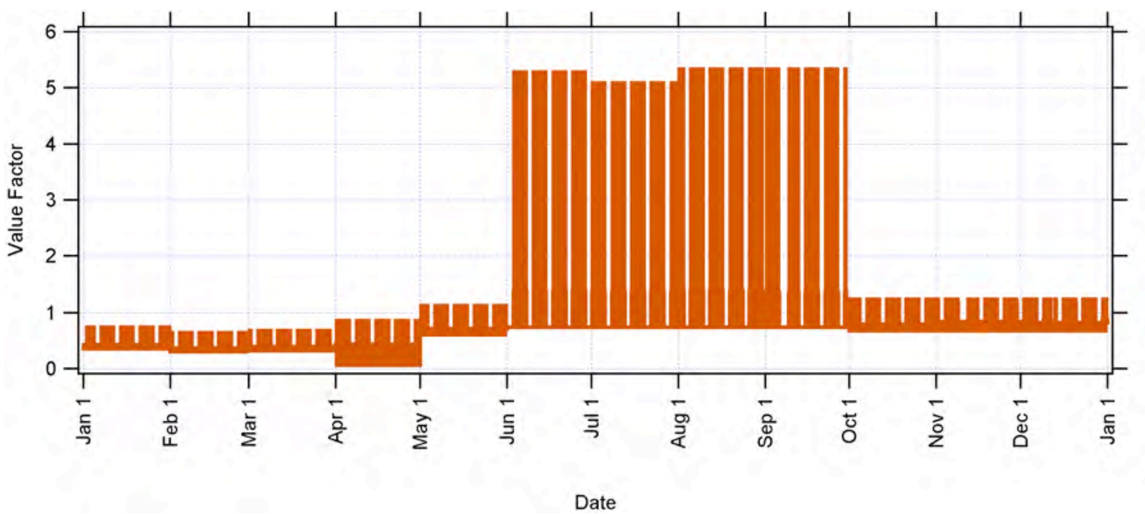

Figure 3.6 Tier Based Value Factor as a Function of Time of Year

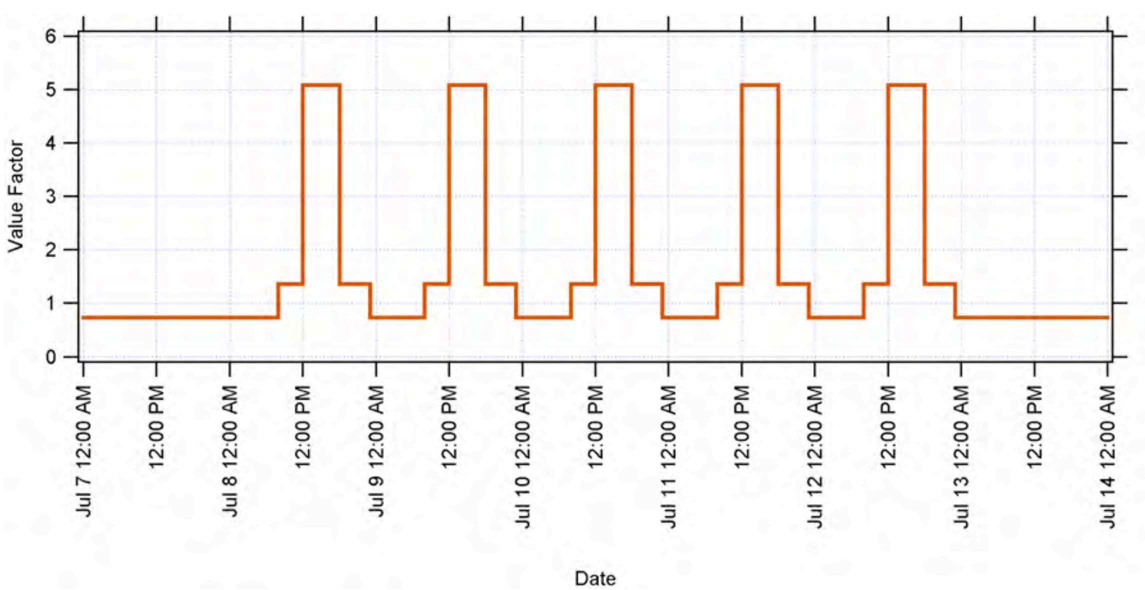

Figure 3.7 Tier Based Value Factor During a Peak Demand Period

The revenue factor is equal to the tier based value factor multiplied by the generator capacity factor. The tier based approach provides a high value for electricity generated during weekday afternoon hours. Figure 3.8 presents the tier based time dependent revenue factor for a peak demand period in July. Figures 3.9 and 3.10 present revenue factor data for periods in July and August.

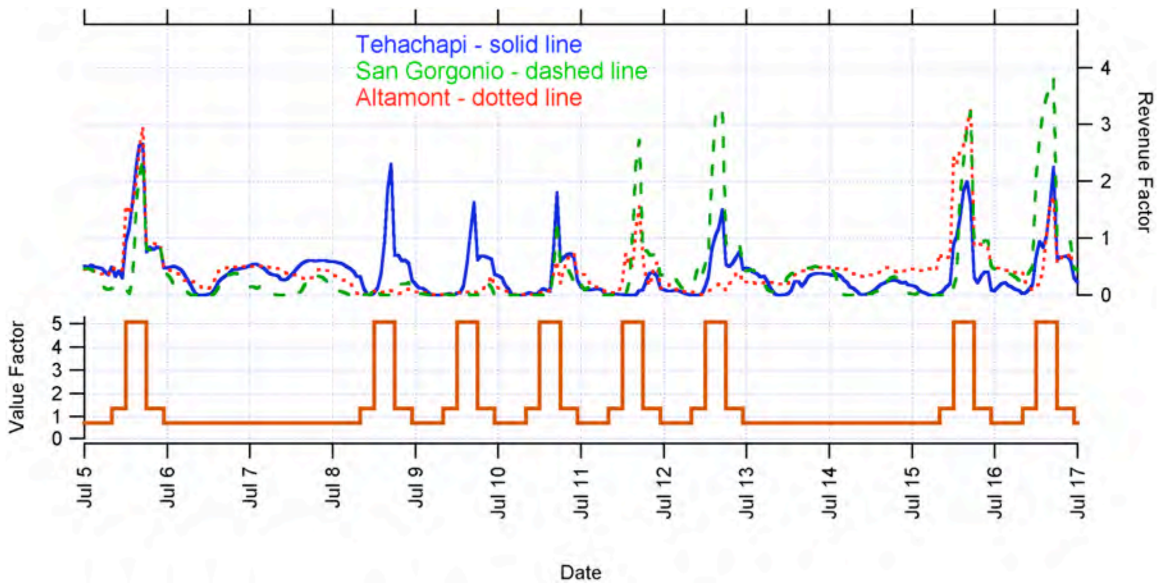

Figure 3.8 Tier Based Revenue Factor During a Peak Demand Period

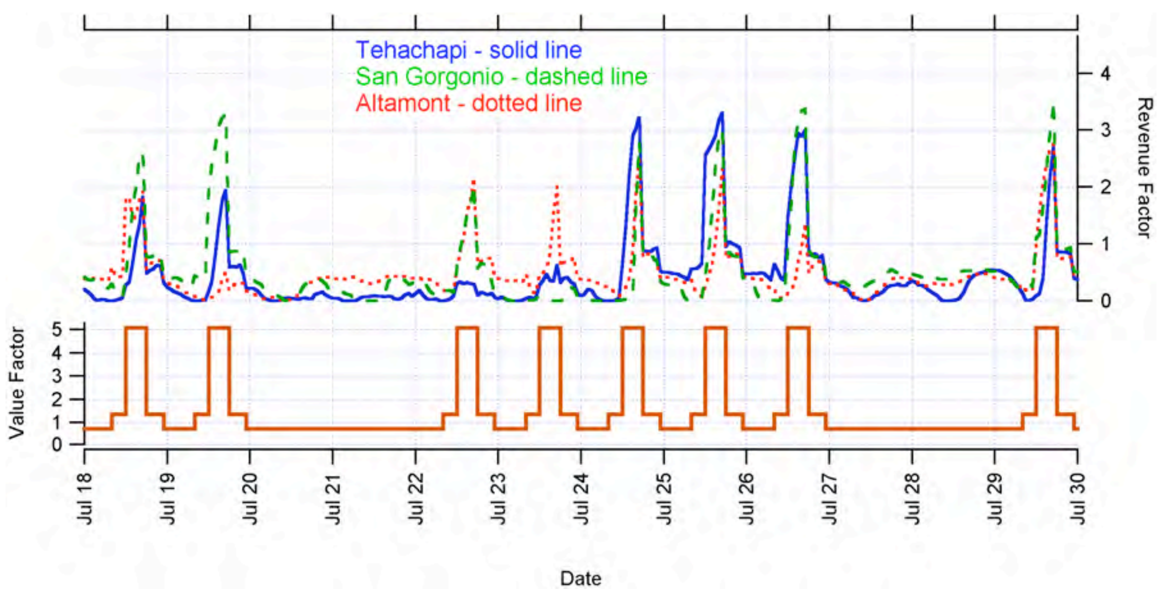

Figure 3.9 Tier Based Revenue Factor During July 2002

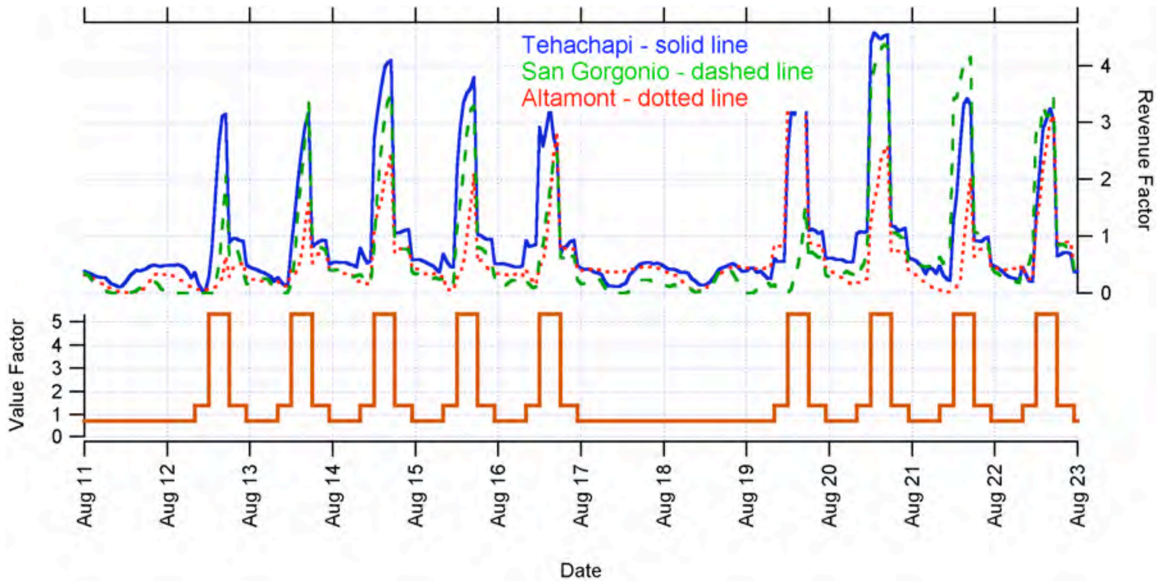

Figure 3.10 Tier Based Revenue Factor During August 2002

Wind generation using the tier based approach shows somewhat greater revenue factors as compared to constant valuation. All three wind sites show improved revenue factors, with Altamont showing the largest gain (12.3%) in revenue factor when compared to the constant valuation approach.

Table 3.2 Tier Based Revenue Factor Comparison Summary

Revenue Factor	Constant Value	Tier Based Value	Constant Value Comparison
Tehachapi	29.7%	31.0%	104.5%
San Gorgonio	30.2%	32.1%	106.3%
Altamont	18.6%	20.9%	112.3%

4 MATCH GENERATION IMPACT ANALYSIS

4.1 Discussion of the Methodology

California's electrical power grid must supply load demand during any given hour of the day. Power can be delivered by in-state generators or imported from other states. In this analysis we will define *system generation* as the electric power which exactly balances load demand. Under this definition *system generation* equals both in-state generation and transmission imports across state borders. We will further define that *system generation* is composed of two sub-components: *trial generation* and *match generation* as shown in equation 4.1.

$$P_{system} = P_{trial} + P_{match} \qquad \textbf{Equation 4.1}$$

The source of *trial generation* may include any potential power source. The trial generator is simply the resource of analysis interest. In the absence of the trial generator the match generation equals the system generation. The addition of power from the trial generator will change the required match generation. For any given hour the difference between *system generation* and *trial generation* results in a *match generation*, which can be determined by equation 4.2.

$$P_{match} = P_{system} - P_{trial} \qquad \textbf{Equation 4.2}$$

We can easily calculate the match generation if data are available for the system and trial generation. The source of trial generation may be a renewable resource which is intermittent in nature. The match generation represents the power needed in the presence of the trial generator. To evaluate the impact of the trial generator we can compare rank ordered match generation against rank ordered system generation. The difference between the rank ordered values provides a quantitative measure of the impact from the trial generator. This approach, called match generation impact analysis, provides a simple mathematical procedure for evaluating the effect of renewable and intermittent generation resources. The analysis steps are as follows:

1. Estimates of hourly system generation and trial generation are prepared.

2. Match generation is calculated as the hourly system generation less the hourly trial generation.

3. System generation is rank ordered from the highest to the lowest power level.

4. Match generation is rank ordered from the highest to the lowest power level.

5. Trial generator impact is calculated as the difference between the rank ordered system and rank ordered match generation requirements.

4.2 Case 1: 1500 MW Wind Capacity

As an example let us consider a case with 1500 MW of wind generation capacity operating in California. For this example we will assume that 645 MW (43%) is located in Tehachapi, 360 MW (24%) in San Gorgonio, and 495 MW (33%) in Altamont. Consider now the year 2002, and assume that wind generation and system load follow trends for that year. The total wind generation can be determined by adding the contributions from each resource area for each hour of the year. The match generation is calculated by subtracting the wind generation from the system generation in each hour.

We can easily compare the match generation to the system generation by rank ordering the time series and plotting them as shown in Figure 4.1. This graph shows that the match generation requirements are less than the system generation requirements over the entire year. Furthermore the graph shows that overall trends remains the same with addition of the trial generator. Match generation with the addition of 1500 MW of wind capacity is reduced in magnitude as compared to system generation.

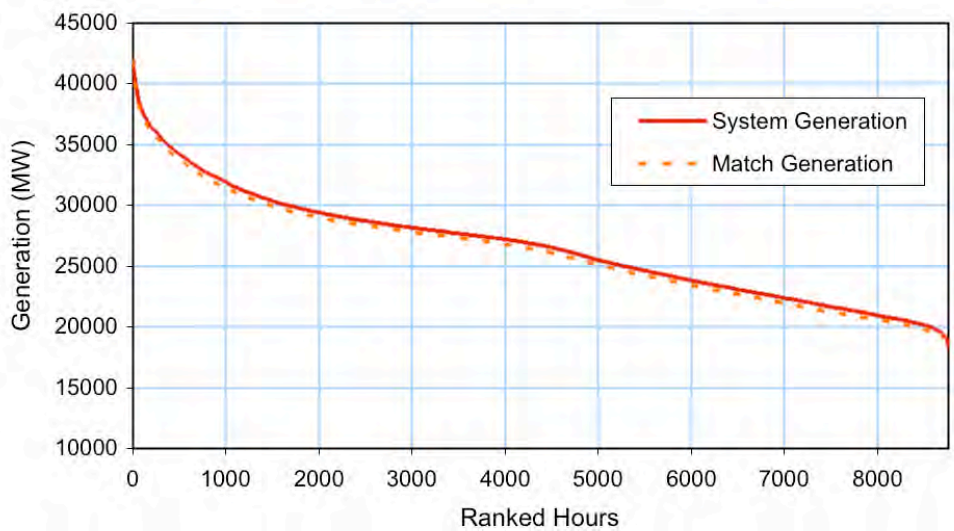

Figure 4.1 Ranked System and Match Generation for Case 1

The impact of wind power can be evaluated by calculating the difference between system and match generation. Subtracting the rank ordered match generation from the rank ordered system generation provides a quantitative assessment of the impact of wind power capacity on in-state generation resources and imports. For this case, the addition of 1500 MW in wind capacity led to a reduction in match generation requirements in excess of 300 MW for

8688 hours (Figure 4.2). The impact of wind power was a reduction in match generation requirements by an amount equivalent to 20% of rated wind capacity for over 99% of total hours in the 2002 analysis year.

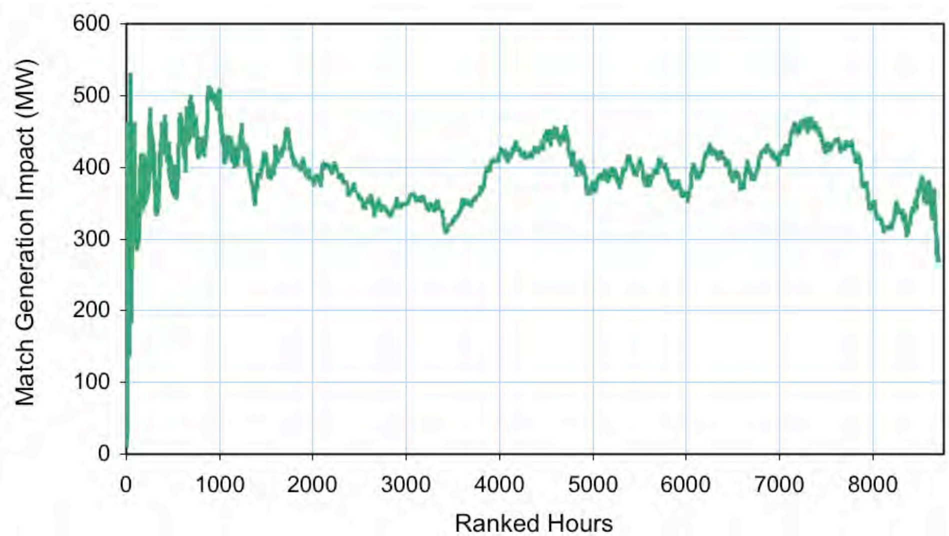

Figure 4.2 Match Generation Impact From Wind Generation for Case 1

Wind generation is valuable in reducing match generation during peak demand periods, although more variability is observed. The impact of wind generation during the top two hundred match generation hours is shown in Figure 4.3 and for the top one thousand match generation hours in Figure 4.4.

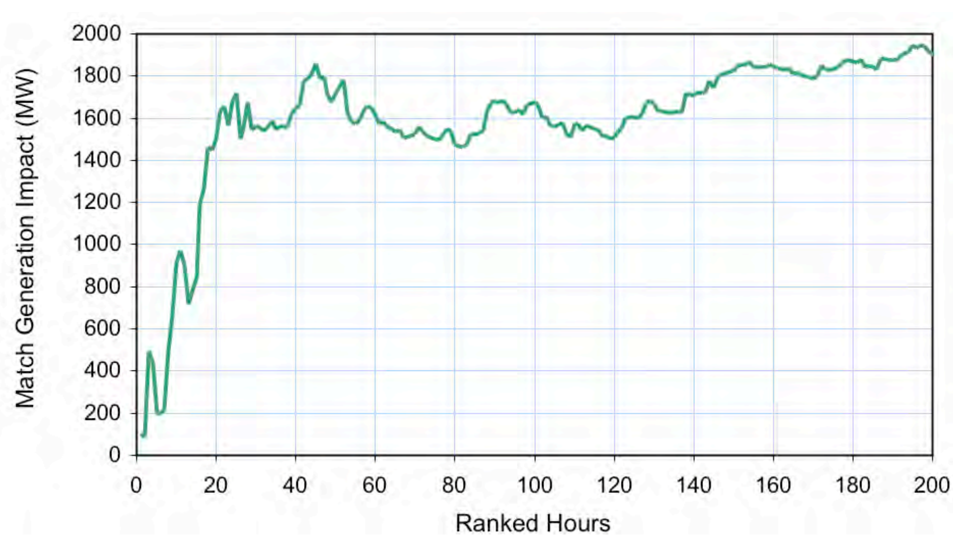

Figure 4.3 Match Generation Impact in Top 200 Hours for Case 1

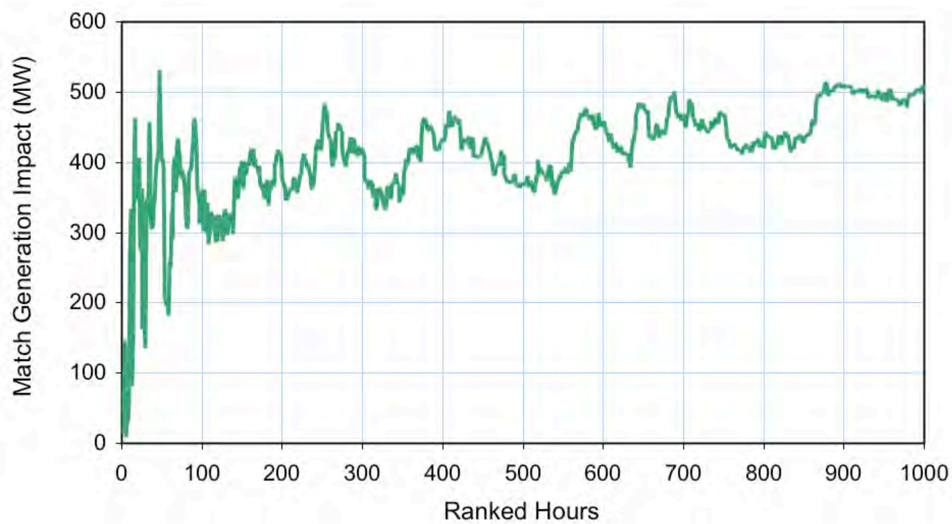

Figure 4.4 Match Generation Impact in Top 1000 Hours for Case 1

4.3 Case 2: 8000 MW Wind Capacity

As our next example let us consider the impact of 8000 MW of wind generation capacity. In this case we will assume that 5200 MW (65%) is located in Tehachapi, 1600 MW (20%) in San Gorgonio, and 1200 MW (15%) in Altamont. This case roughly approximates the total wind generation estimated to meet RPS requirements. A comparison of the ranked system and match generation is provided in Figure 4.5. This graph shows that wind power resources substantially reduce match generation requirements over the entire year. Again, the impact of wind generation was quantified by subtracting the rank ordered match from the rank ordered system generation. This analysis indicates that wind generation impact is most significant when demand is low, as shown in Figure 4.6.

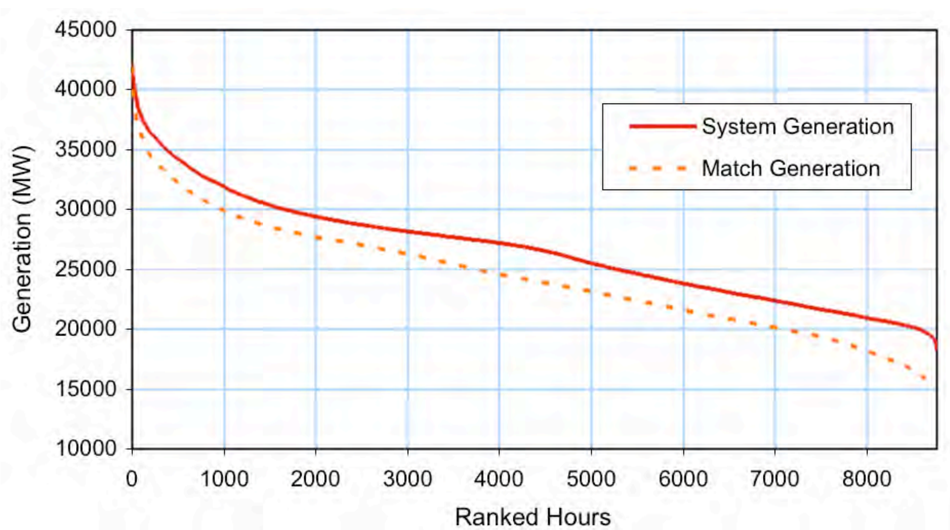

Figure 4.5 Ranked System and Match Generation for Case 2

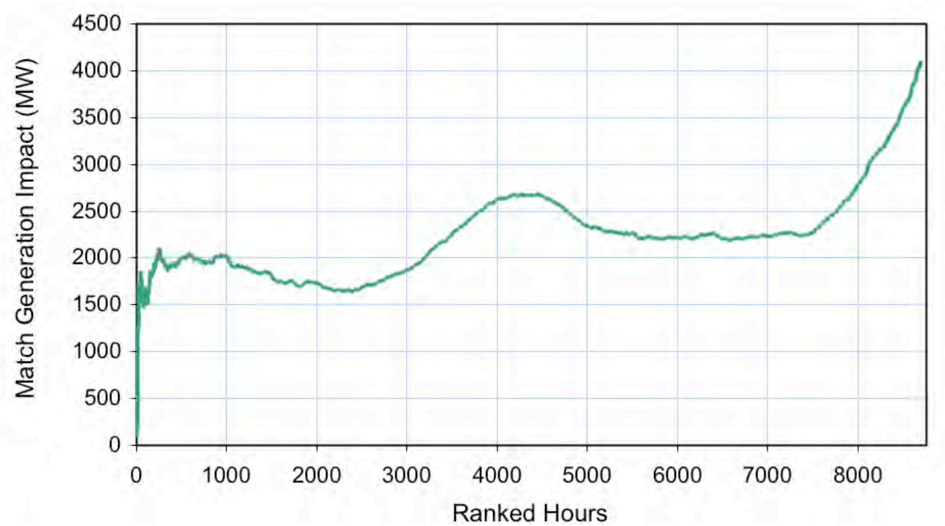

Figure 4.6 Match Generation Impact From Wind Generation for Case 2

The impact of wind during high load periods is relatively consistent, except for the top twenty load hours as shown in Figure 4.7. Wind generation is nearly constant at 2000 MW (25%) for most of the top one thousand hours as shown in Figure 4.8. The match generation impact due to the inclusion of 8000 MW in wind resources exceeded 1600 MW (20% of rated capacity) for 8677 hours, representing over 99% of the 2002 analysis year. The match generation impact analysis methodology shows that the wind power plays a positive role in reducing the need for conventional generation and imports.

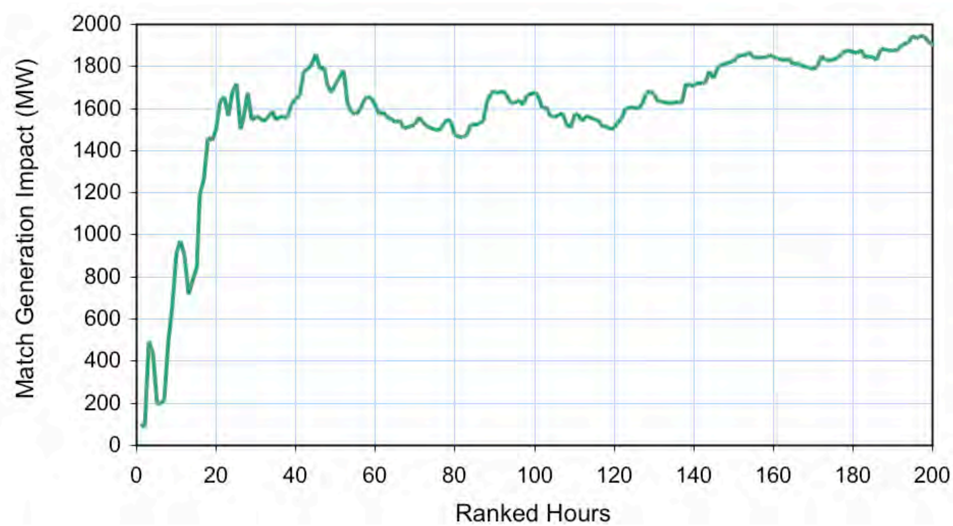

Figure 4.7 Match Generation Impact in Top 200 Hours for Case 2

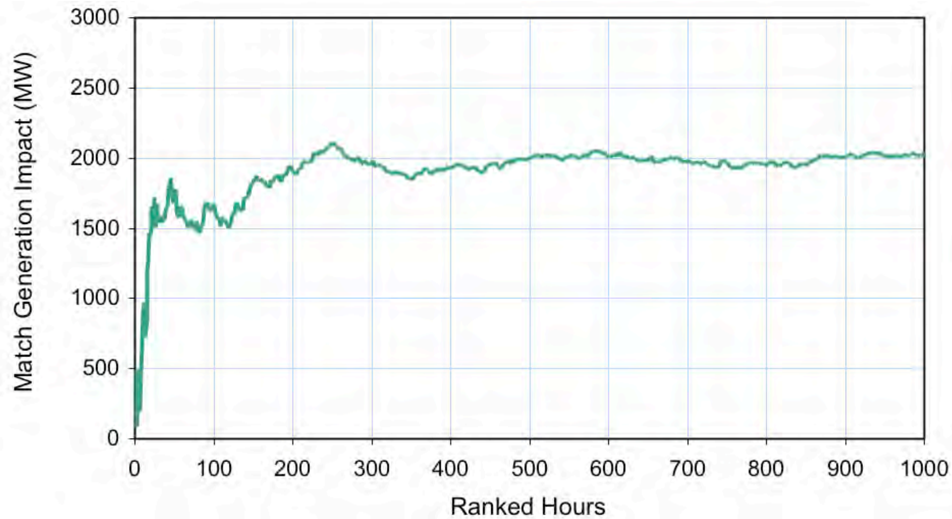

Figure 4.8 Match Generation Impact in Top 1000 Hours for Case 2

5 REFERENCES

1. California Energy Commission, "Renewable Resources Development Report", ENERGY COMMISSION 500-03-080F, November 2003.